BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF COLORADO

PROCEEDING NO. 19R-0096E

IN THE MATTER OF THE PROPOSED AMENDMENTS TO RULES REGULATING ELECTRIC UTILITIES, 4 CODE OF COLORADO REGULATIONS 723-3, RELATING TO ELECTRIC RESOURCE PLANNING, THE RENEWABLE ENERGY STANDARD, NET METERING, COMMUNITY SOLAR GARDENS, QUALIFYING FACILITIES, AND INTERCONNECTION PROCEDURES AND STANDARDS

COMMENTS OF
THE COLORADO ENERGY OFFICE

May 1, 2019

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The Colorado Energy Office ("CEO"), by and through its undersigned counsel, hereby submits comments related to the above-captioned matter, pursuant to Public Utilities Commission ("Commission") Decision No. C19-0197. CEO appreciates the opportunity to provide comments for the Commission's consideration in response to its Notice of Proposed Rulemaking ("NOPR") to amend the Commission's Rules Regulating Electric Utilities, 4 Code of Colorado Regulations ("CCR") 723-3.

INTRODUCTION

CEO is a state agency, statutorily charged with sustaining Colorado's energy economy and promoting all Colorado energy, as well as promoting energy efficiency, increasing energy security, lowering long-term consumer costs and protecting the environment. *See* § 24-38.5-101 C.R.S. CEO's statutory duty includes "[w]ork[ing] with communities, utilities, private and public organizations, and individuals to promote… [c]lean and renewable energy, such as wind, hydroelectricity, solar, and geothermal," and "[e]nergy efficiency technologies and practices." *See* § 24-38.5-102, C.R.S. CEO's mission is to deliver cost-effective energy services and advance innovative energy solutions for the benefit of all Coloradans.

Previously, CEO provided two rounds of comments and proposed redline rules in the "Stakeholder Outreach Proceeding" (Proceeding No. 17M-0694E), addressing the Commission's rules implementing the state's renewable energy standard ("RES"); rules related to interconnection; rules providing guidance on qualifying facilities ("QFs"); new rules related to distribution system planning ("DSP"); and rules governing the electric resource planning ("ERP") process. In preparing these previous comments, CEO worked with a number of other interested participants to develop the collaborative redline rules that were provided as attachments in that proceeding.

CEO appreciates the opportunity to provide comments to the Commission in support of CEO's mission. CEO is not proposing new rule language at this time, but we intend to provide redline proposals at a later date.

CEO welcomes the Commission's retention of competitive bidding in electric resource planning and the overall effort to streamline and clarify the resource planning process. CEO also welcomes the discussion about the best way to integrate RES and other planning processes with the ERP process and supports a pre-ERP process among stakeholders. We support the Commission's proposed changes that provide opportunities for Colorado's low-income and underserved groups to participate in and benefit from the development of clean energy that can help reduce their energy burden. CEO's comments reflect not only our statutory duties; we also propose changes that further Governor Polis' climate and energy goals including: decarbonizing the grid, electrifying transportation, advancing other beneficial electrification, and ensuring that all Coloradans have a reasonable opportunity to benefit from clean energy. These initial comments explain CEO's continued support for many of the modifications it proposed in the Stakeholder Outreach Proceeding and, in places, expand on those proposed modifications. CEO's comments address all the topics in the NOPR.

CEO recognizes that the Commission undertook significant efforts to hear from different stakeholders on a range of issues as part of its Stakeholder Outreach Proceeding. CEO notes that the Commission appears not to have adopted many of the consensus proposals that we recommended. Further, as discussed in our comments, CEO views several of the Commission's draft proposal as departures from current practice.

COMMENTS

I. Definitions (3001)

CEO recommends that the Commission add a definition of Distributed Energy Resource ("DER") to the definition section.

The rules currently define and reference "demand-side resources," which include energy efficiency, energy conservation, load management, and demand response or any combination of these measures. CEO believes that this definition leaves out other important technologies that should be considered in planning such as distributed renewable generation, energy storage, electric vehicles, and microgrids. CEO recommends that the Commission adopt a definition of DERs includes both the demand-side resources already defined in the Commission's rules but represents a larger category of resources including just listed.

II. Electric Resource Planning Rules (3600-3617)

The ERP rules establish a process to develop portfolios of electric generation resources that cost-effectively meet the energy needs of Colorado's public utilities. As stated in Rule 3601, it is a policy of the state of Colorado that a primary goal of electric resource planning is to minimize the net present value of revenue requirements ("NPVRR"). In addition to minimizing NPVRR, the Commission must give the fullest possible consideration to the cost-effective implementation of new clean energy and energy-efficient technologies. The general intent of CEO's proposed modifications to the ERP Rules are to (1) ensure utilities are, to the extent possible, integrating other planning process with resource planning; (2) increase the transparency and inclusiveness of the ERP process and allow for more robust stakeholder engagement; (3) ensure the rules encourage the adoption of eligible energy resources, and particularly, distributed energy resources ("DER"); and (4) reduce the carbon intensity of Colorado's electricity generation. These comments discuss

CEO's recommended modifications rule by rule and address a number of the Commission's questions related to the ERP Rules.

A. Rule 3600: Applicability

CEO recommends that the Commission subject Tri-State Generation and Transmission Association's (Tri-State) resource planning process to the same level of scrutiny as plans submitted by other public utilities. CEO submits that reducing carbon emission in Colorado requires reducing emissions from all the state's public utilities and that stronger Commission oversight of Tri-State is a key to meeting carbon reduction goals.

Currently, the Commission does not require Tri-State to participate in the same resource planning process as the other public utilities that are not exempt from Commission oversight. CEO recommends the Commission require Tri-State to seek review of its resource need and its acquisition of new generation and transmission resources through the full ERP process, and that the Commission apply the same standards of review regarding minimizing NPVRR and meeting other state policy goals to Tri-State that it applies to other utilities. As discussed below, CEO supports the Commission's view that it possesses the legal authority to require Tri-State to file a resource plan for approval by the Commission, and CEO believes that doing so would further state policies and better ensure that more Coloradans see the benefits of a transition to renewable energy resources including lower energy costs, cleaner air, and reduced greenhouse gas emissions.

The Commission has long held that it has authority to require Tri-State to file an ERP and to apply for a Certificate of Public Convenience and Necessity ("CPCN") for new resources.[1] To date, the Commission has declined to assert its authority and has instead

[1] *See* Decision Nos. C09-0092, ¶¶ 4-8, and C10-0101, ¶ 15, in Proceeding No. 09I-041E.

merely required Tri-State, through Rule 3605, to file a report showing its load forecasts, an assessment of existing resources, its planning reserves, and a needs assessment.

The Commission's authority over Tri-State stems from its Constitutional authority over public utilities. The Commission's authority under article XXV of the Colorado Constitution is not narrowly confined, rather it extends to incidental powers that are necessary to enable it to regulate public utilities.[2] The Public Utilities Law provides additional authority and restrictions on the Commission's jurisdiction over public utilities in Colorado. By statutory definition, Tri-State is a public utility because it is an "electrical corporation" in Colorado that "operat[es] for the purposes of supplying the public."[3] Tri-State is not considered a "cooperative electric association,"[4] therefore, it cannot exempt itself from Commission jurisdiction.[5] In fact, the Commission recently reaffirmed its authority to regulate the rates, charges, and tariffs of Tri-State.[6]

Further support for the Commission's authority over a public utility's generation and transmission resource planning process comes from the requirement of a public utility to first obtain a CPCN from the Commission before constructing "a new facility, plan, or system or extension if its facility, plant, or system."[7] Because Tri-State is a public utility and it is not exempt from the statutory CPCN requirement, Tri-State is not exempt from participating in the Commission's ERP process. As stated above, the Commission has chosen not to require Tri-State to file ERPs in the past, but it has always had the authority to do so.

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[2] Colo. Const. art. XXV.
[3] § 40-1-103, C.R.S. (public utility defined).
[4] § 40-9.5-102, C.R.S.
[5] *See* § 40-9.5.103, C.R.S. (allowing cooperative electric associations to vote to exempt themselves from Commission jurisdiction.).
[6] Decision No. C19-0297-I, ¶¶ 16-27, in Proceeding No. 18F-0866E.
[7] § 40-5-101, C.R.S.

CEO suggests that the time is ripe for the Commission to require Tri-State to participate in a more robust ERP process that assesses the utility's proposed resource need and reviews and approves the resources proposed to meet that need in order to ensure that Tri-State's resource plan minimizes the NPVRR and meets other state policy goals.

Tri-State serves 18 electrical cooperatives in Colorado. Under the Commission's current approach, Tri-State files its report informing the Commission of its resource need. The Commission may choose to hold a hearing and solicit public comment on the report and it may issue a decision "express[ing] its opinion" about Tri-State's plan, but the Commission does not approve, modify, or deny Tri-State's plan for meeting its future resource need.[8] Recently, the Commission has not held a hearing or issued any opinion about a Tri-State resource report. Unlike the more rigorous approach taken with the other public utilities, there is no opportunity for a third-party to review the assumptions that Tri-State makes to support its proposed resource need. Nor is there a neutral setting, such as a Commission hearing, for stakeholder input or feedback on the plan's cost-effectiveness, whether the plan gives fullest possible consideration to the cost-effective implementation of new clean energy technologies, or whether the plan reduces carbon emissions. Finally, because the Commission does not evaluate the Tri-State resource plan, Tri-State is not subject to the requirements of minimizing NPVRR or using renewable energy to the maximum practicable extent that other public utilities are subject to. In short, while Tri-State may choose to comply with state public utility planning goals on a voluntary basis, because there is no review or oversight there is no way to ensure that they are meeting those goals.

Requiring Tri-State to undergo a regular ERP filing could also advance the state goal of addressing climate change by reducing greenhouse gas emissions from electricity

[8] Decision No. C10-0101, ¶ 9.

generation throughout Colorado. The Commission's proposed changes to the ERP rules include adding language to Rule 3604(k) requiring an "assessment of potential cost-effective early retirements of utility-owned resources with retirement dates during the planning period." Tri-State currently meets roughly 49% of its customer's needs with coal-fired generation. Requiring Tri-State to submit an ERP for Commission review and approval would provide an opportunity for Tri-State members and the Commission to evaluate whether Tri-State's coal units continue to be economic for its members or whether there are lower-cost and cleaner alternatives to meet that energy need.

B. Rule 3601: Overview and Purpose

In its proposed Rule 3601(c), CEO recommends adding language related to how electric resource planning should be an integrated process that takes into account other types of utility planning and activities that effect a utility's load or need for new generation such as demand-side management ("DSM") planning, transmission planning, RES planning, vehicle or beneficial electrification planning, and the use of non-wire alternatives as part of distribution system planning. Integrating information from these other planning processes, such as reduced load, shifting load to off peak periods or periods of maximum renewable production, adding new load that allows better integration of renewables, or increased generation, will ensure a more holistic perspective of the utility's need, increase the use of DERs, and expand customer choice.

CEO recommends adding the following language to Rule 3601(c): "It is the policy of the State of Colorado to utilize renewable energy resources to the maximum practicable extent to save consumers and businesses money, attract new businesses and jobs, promote the development of rural economies, and minimize water use for electricity generation."

CEO also recommends that the Commission adopt language stating that it is a goal of electric resource planning to minimize carbon dioxide and other greenhouse gas emissions

from electricity generation in order to protect and preserve the state's natural resources and environment.

C. Rule 3602: Definitions

CEO proposes retaining the definition of "Section 123 resources." CEO further recommends modifying the definition to clarify the kind of resources that can be considered Section 123 resources and adding the phrase "environmentally beneficial" to describe the allowable energy technologies or demonstration projects. While CEO agrees with the Commission's statement that it no longer makes sense to presume that wind and solar are more expensive than the other resources that compete in Phase II resource solicitations, CEO suggests that removing the definition of a Section 123 resource is premature. Neither CEO nor the Commission can foresee what clean technologies may yet emerge over the coming years that could fit into the definition of a Section 123 resource and would benefit from the different standard of review that applies to those resources in Phase II of an ERP. CEO suggests that the definition of a Section 123 is an essential tool that the Commission can use to consider not yet price competitive technologies that will help create new renewable and clean energy technology markets and reduce carbon and other emissions within the ERP process.

D. Rule 3603: ERP Filing Requirements

In the NOPR, the Commission asks for input on proposed Rule 3603 and whether the Commission should adopt different ERP requirements and procedures for Public Service as compared to Black Hills due to its much smaller size.

CEO recommends the Commission apply the same ERP requirements and procedures equally to all public utilities including Black Hills, Public Service, and Tri-State. If there are specific ERP requirements that a utility believes pose a particular administrative burden, such as the filing of specific reports, the utility can request a waiver

of that requirement. If the Commission finds that a utility is consistently unable to meet certain requirements, then it might consider addressing by rule whether those specific provisions should continue to apply.

E. Rule 3604: Contents of the ERP

In proposed Rule 3604, CEO recommends several additions to a Phase I ERP filing that add to the transparency of the resource planning process, including: projected emissions of existing resources; fuel price forecasts; the methodology for evaluating of bid contracts for renewable energy credits ("RECs") without associated energy; the assessment of the costs of existing and proposed resources, including fuel costs, operating costs, regulatory carbon dioxide costs and externalities, or social costs of carbon dioxide emissions; and a description of the modelling assumptions, inputs, and software the utility proposes to use to evaluate bids and existing resources in Phase II. CEO also addresses the Commission question about additional procedures and processes related to the ERP.

Consistent with our recommendation that the Commission retain the definition of a Section 123 resource and adopt rules for distribution system planning, CEO recommends that the Commission does not remove the requirement for a utility to file alternate plans under Rule 3604. CEO supports the Commission's inclusion in Rule 3604 of a requirement for a utility to address the potential early retirement of utility-owned resources during the planning period as one possible alternative.

The Commission also seeks input on the use of scenarios in resource planning, the integration of resource planning with other planning processes, and whether the Commission should open a proceeding prior to the ERP for the purpose of receiving certain studies. CEO supports all three approaches and, as discussed below, recommends that they could be combined to achieve a better integrated and more efficient ERP process.

CEO suggests that Commission adopt a rule establishing a non-litigated, pre-ERP filing process, and further recommends that this proceeding require a utility to participate in stakeholder workshops related to the filings made in the proceeding. CEO believes that this proceeding and stakeholder process could reduce some of the administrative burden in the ERP proceeding and provide additional administrative efficiencies. Through this proposed process, CEO and other stakeholders could engage with the utility outside of the formal requirements of a litigated proceeding to review the utility's proposed scenarios and provide feedback or make recommendations for changes to those scenarios that a utility could incorporate in its initial filing. The stakeholders could also informally review and comment on the other reports and information that a utility is required to file in an ERP proceeding. The stakeholder process could also be a venue for clarifying the specific software model and inputs that the utility will be using in the ERP. Finally, a non-litigated pre-ERP process could provide an opportunity for the Commissioners to engage with one another at public meetings, and through this dialogue, to inform the utility and other stakeholders about what they would like to see included or addressed in the ERP filing.

The Commission also asked whether it should endeavor to develop different sets of assumptions about the future for exploring possible risks that may arise from those assumptions in an ERP context, and whether such assumptions should be part of the Phase I proceeding or precede the utility's development of its initial ERP filing. In response to this question, CEO suggests that instead of the Commission developing different sets of assumptions about the future, it require the utilities to develop and present the scenarios it believes to be the most relevant in the pre-ERP stakeholder proceeding. This would allow interested stakeholders to engage with the utility on changes to the scenarios or to propose alternative scenarios. The Commission could also engage with the utility to provide feedback on whether it would like to see changes to the scenarios or see additional

scenarios. The utility could include this feedback into the development of the scenarios that it files with the ERP. In the alternative, the Commission could require that scenarios be included as part of the utility's Phase I filing so that the Commission and interveners could review and provide feedback on these scenarios. The scenarios could also be a topic of discussion in the stakeholder workshop CEO is recommending that would precede the filing of the ERP.

Finally, CEO recommends that the Commission consider directing a utility use the social cost of carbon ("SCC"), as defined by the Interagency Working Group, in the development of its base case optimization. This would allow the Commission and other interveners the opportunity to understand the impact of carbon emissions in the first model run and to assess any alternatives developed against this base case.

F. Rule 3605: Cooperative Electric Generation and Transmission Association Reporting Requirements

CEO recommends eliminating this rule if the Commission adopts CEO's recommended modifications to proposed Rule 3600 related to the applicability of the ERP rules to Tri-State. In this case, reporting requirements for Tri-State would be located in other sections of the rules.

G. Rule 3606: Electric Energy and Demand Forecasts

CEO recommends adding language to proposed Rule 3606(e) that requires utilities to explain the relevant forecast inputs and assumptions derived from the utility's demand side management reports and plans and any future distribution system planning reports and plans in the description and justification section related to energy and demand forecasts. This change is in line with the goal of creating a more integrated resource planning process, as discussed above.

H. Rule 3607: Assessment of Existing Resources

In the NOPR, the Commission requested legal arguments regarding whether it has authority to assess existing resources in the Phase I of an ERP proceeding. Sierra Club provides an extensive legal analysis in its initial comments and concludes that:

> Commission evaluation of existing resources is necessary to accomplish the legislative functions delegated to the Commission, namely, the Commission's mandate to ensure that all charges made, demanded, or received by any public utility for any rate, fare, product, or commodity furnished or to be furnished or any service rendered or to be rendered shall be just and reasonable.[9]

Sierra Club also concludes that "there is no Constitutional or statutory provision that bars the Commission from assessing the economics of, and need for, a utility's existing resources."[10] Finally, Sierra Club notes that Commission evaluation of existing resources in the context of a Phase I ERP would not require the Commission to second-guess its prior prudency determinations.[11] CEO agrees with Sierra Club's legal analysis and we do not believe that further legal argument is necessary.

CEO appreciates the Commission's addition of a benchmarking provision within rule 3607 that requires a utility to compare the costs and performance of existing resources to the costs and performance of the generic resources. While CEO generally supports this concept, it also recommends some additional language that will go further to ensure that utilities are acquiring and utilizing the most competitively priced resources possible and passing those savings on to ratepayers. CEO's proposed rule language also provides the Commission with the information it needs to give the fullest possible consideration to the cost-effective implementation of new clean energy.

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[9] Initial Comments of Sierra Club, filed on March 29, 2019, at 2 (internal citations omitted).
[10] *Id.* at 4.
[11] *Id.*

In the utility's assessment of existing resources, in proposed Rule 3607(a)(V), CEO recommends the Commission require utilities to provide additional information on the existing resources by facility, including estimated incremental decommissioning costs not included in the depreciation expense, remaining depreciation expense and identification of potential new capital or maintenance expenses for their estimated remaining useful lives, and actual expenses of utility-owned generation facilities since the filing of the most recent ERP.

In proposed Rule 3607, CEO recommends providing additional guidelines for utilities related to the evaluation of the early retirement of existing resources, including that utilities shall evaluate early retirement during the resource acquisition period for each existing utility-owned generation facility that has a terminal date within 15 years of the end of the resource acquisition period. In addition, for each of these, the utilities shall provide the cost of early retirement, the estimated operational and capital savings from early retirement, and accelerated depreciation costs, as well as describing the replacement resource need, possible system reliability impacts and corrective actions for such impacts, and how the retirement can be represented in modeling for fair comparison of costs and benefits against alternative resources.

CEO also recommends requiring the utilities to assess existing "distributed energy resources" in addition to "demand side resources," which would include resources acquired through net metering, CSGs, RES Compliance Plans, Demand Side Management Plans, and any future Distribution System Plans. This will support the intent of creating a more integrating ERP process.

I. Rule 3608: Transmission Resources

CEO recommends adding language to proposed Rule 3608(d) that clarifies that in the utility's consideration of transmission costs and benefits in its comparison of possible

resource alternatives, transmission benefits shall include the ability to connect greater amounts of renewable energy. This provision would encourage utilities to consider the longer-term benefits of future renewable development, which is important for continuing to move toward the state's renewable energy goals.

J. Rule 3609: Planning Reserve Margins and Contingency Plans

CEO recommends adding a provision to proposed Rule 3609 that requires the utility to utilize distributed energy resources, including demand side resources, as its priority and first source of contingency resources. CEO also recommends the Commission direct a utility to consider the geographic and resource diversity of its existing renewable resources as it calculates the needs for a planning reserve margin. CEO proposes that the Commission direct staff to lead a workshop among interested stakeholders on developing an appropriate mechanism for calculating the planning reserve margin.

K. Rule 3610: Assessment of Need for Resources

CEO proposes reorganizing and modifying proposed Rule 3610 in order to clarify that, in addition to considering the energy and demand forecasts and planning reserve margins, the utility should consider early retirement of existing resources, demand side resources, DERs and energy from QFs, pursuant to Rule 3607. CEO also suggests the Commission require the utility to present future costs of energy efficiency and demand response resources and include these as alternatives to new and existing resources in its portfolio modeling. This will ensure the utility is implementing cost-effective demand-side resources to reduce the need for additional resources that would otherwise be met through a competitive acquisition process.

L. Rule 3617: Amendment of an Approved ERP

CEO recommends the Commissions add language to proposed Rule 3617 that requires any application for approval of amendments to an approved ERP to include any

proposed changes to solicitation documents, request for proposal documents or standard contracts. This will ensure that the Commission and intervenors have the opportunity to review and provide feedback on the new documents.

III. Renewable Energy Standard Rules (3650-3668)

The renewable energy standard rules are integral to advancing clean and renewable energy in Colorado, establishing a process to implement the Renewable Energy Standard ("RES") for utilities in Colorado, pursuant to §§ 40-2-124 and 40-2-127, C.R.S. CEO references the overview and purpose of the Renewable Energy Standard Rules (current and proposed Rule 3651), and maintains that this continues to be the appropriate framework for the RES rules and any proposed revisions:

> Therefore, in order to save consumers and businesses money, attract new businesses and jobs, promote development of rural economies, minimize water use for electricity generation, diversify Colorado's energy resources, reduce the impact of volatile fuel prices, and improve the natural environment of the state, **it is in the best interests of the citizens of Colorado to develop and utilize renewable energy resources to the maximum practicable extent**. *(Emphasis added.)*

As such, CEO recognizes two important components contained in RES Rules: compliance with the RES and small eligible energy resource planning. In its comments, CEO provides its perspective on both of these components but places a greater emphasis on the acquisition of small eligible energy resources. As discussed in greater detail below, CEO is still reviewing several of the Commission's proposals, and intends to submit rule revisions at a later date.

Several modifications contemplated in the proposed RES Rules represent significant departures from current practices. For example, the proposal that net metering is a means by which investor-owned utilities cause eligible energy to be generated and the implication that the energy could therefore be counted for the demonstration of compliance with the RES is new and could have unforeseen consequences. CEO recognizes that the conversation

about RECs and RES compliance occurs at a time when a growing number of Public Service customers are pursuing retail renewable distributed generation outside of utility incentive programs. However, the shift to counting such energy for compliance or to using a net metering credit to show a utility "caused" generation raises several issues. As discussed below, CEO requests that the Commission engage with stakeholders after the initial hearing so that we may better understand the Commission's intent for this rule change.

In addition to CEO's concern about the apparent shift away from RECs, we are concerned about the impacts of the Commission's proposal to reduce the standard rebate offer to $0 from the $2.00 that is currently in rules. As CEO stated in our comments and proposed rule modifications in the Stakeholder Outreach Proceeding, and again in these comments, we maintain that certain incentives—including upfront or production-based incentives—are still needed to support access to renewable energy for underserved customer groups and low-income customers. CEO recommends that the Commission require utilities to retain the Standard Rebate Offer at $2.00 in rules as a possible incentive. CEO recognizes that, although RESA funding has successfully fostered certain markets, a more directed approach to incentives still may be necessary to support hard-to-reach market segments. Utilities and stakeholders have practices for identifying and including this population segment in RES planning.

Consistent with CEO's mission and with our comments in the Stakeholder Outreach Proceeding, CEO again asks the Commission to add a definition for underserved customers in the RES rules. CEO maintains that there are customers or customer groups—beyond those currently recognized through traditional definition of low-income—who would benefit from additional incentives in order to be able to participate in retain distributed generation programs. These groups are considered underserved because they are part of a hard-to-reach market segment. These customers face challenges that currently prevent them from

participating in those programs, and CEO believes that incentives may help these groups overcome these barriers. For example, customer groups including "renters" and "agricultural customers" are specifically identified in § 40-2-127, C.R.S., as groups that should be able to participate in CSGs, but CEO understands that those groups may be participating at lower levels than other groups. Not all renters or agricultural customers necessarily qualify for low-income programs. Nor is either group associated with a special rate class or meter.

In addition, CEO suggests that a tailored approach to incentives may allow for certain new uses of a utility's RESA funds while still reserving a portion of those funds to support the programs that traditionally have received them. CEO suggests that a key role for the Commission under the new Electric Rules should be to decarbonize utility electric systems while appropriately balancing acquisition of grid-scale resources with the opportunity for customers to participate through distributed renewable resources. We suggest that the Commission should be especially mindful of ensuring reasonable opportunities for both low-income and underserved customers to participate.

A. Rule 3654: Renewable Energy Standard

Throughout the NOPR, and in this section, the Commission appears to propose a substantial change in how a utility demonstrates compliance with its obligation under the RES. Under current practice, a utility typically demonstrates that it has caused retail distributed generation to be generated through the provision of a payment to the customer for the purchase of the REC, which represents the positive environmental benefits from the use of the eligible energy resource. The language in the NOPR appears to suggest that a utility can claim that a net metering credit is sufficient to show the utility "causes" eligible energy to be generated, thus giving the utility the right to count the energy generated for

compliance with its RES obligations, even if the utility is not purchasing the RECs from the customer.

CEO believes this proposal could have unintended consequences, and suggests that the Commission take additional time to inform stakeholders about the reasoning behind this change so we can better understand and evaluate the consequences of using something other than RECs for compliance with the RES. CEO is concerned that separating RECs from RES compliance and using a net metering credit to show that a utility has caused eligible energy to be generated could have significant implications for RES compliance, as well as the broader distributed generation market. For example, if the RECs are no longer needed for compliance, what impact will that have on the price of RECs?

CEO believes that the ability for customers to retain RECs—and therefore claim the environmental benefits of using renewable distributed generation—is an important component of using retail distributed generation for those customers and for retail distributed generation policy in general. Customers that participate in a utility standard offer program receive two different payments, a net metering credit and a production based incentive payment that gives the utility a right to claim the REC, or the environmental benefits, of the generation. The changes proposed in the NOPR could erode the ability of customers that do not participate in a utility rebate offer program to retain the RECs, or environmental benefits, of their retail distributed generation, by allowing a utility to claim those benefits simply because the customer earns a net metering credit. In short, as CEO understands the Commission's proposal, the utility would no longer need to offer a payment for the REC. Previous CEO comments and redlines in the Stakeholder Outreach Proceeding have highlighted the distinction between RECs and incentives, including advocating for the importance of untangling these two features. CEO encourages additional broad stakeholder discussions after the initial hearings on this proposed change.

It is also unclear from the Commission's proposed change whether retail distributed generation would still generate RECs. If so, it might lead to double counting of environmental benefits. For example, if a customer-owned distributed generation system does generate a REC, it appears that the customer would retain the REC and the utility would count the kWh of electricity generated to show compliance with the RES. This, however, appears to let both the customer and the utility claim environmental benefits from the same distributed generation system. At minimum, CEO proposes that any approach adopted by the Commission on the "cause" of renewable generation should contain clear procedures that avoid any double-counting of RECs. In addition to gaining a greater understanding of the implications of and reasoning behind this policy, CEO requests additional time to evaluate how this policy would affect utility compliance with the RES.

CEO believes that such a significant departure from current practice merits more time and discussion among stakeholders and the Commission to better understand the motivation behind this proposed change as well as the implications and consequences of this proposal.

B. Rule 3656: RES Compliance Plan

CEO supports the Commission's efforts to streamline RES compliance planning and to better integrate RES planning with the ERP process. CEO asks the Commission to consider whether the timing of the RES and ERP filings proposed in the NOPR represents the most efficient or advantageous approach to integrating the various planning processes that come before the Commission. CEO notes that there are additional planning processes that may inform either the ERP or the RES that are not included in the current approach to integration. For example, it appears that the Commission does not attempt to integrate transmission planning in the resource planning process, which may be necessary to facilitate the acquisition of utility scale eligible energy resources from Colorado's energy

resource zones. Further, the Commission does not include distribution system planning within the scope of this NOPR or within its current efforts to integrate resource planning processes. CEO recommends that the Commission require each investor-owned utility to file a Distribution System Plan, and we suggest that those plans be included in the Commission's efforts to integrate resource planning processes.

While CEO supports aspects of the NOPR, we note that several significant changes in the RES rules are proposed without specific comments or discussion as to why the changes are being made. For example, a new framework is introduced in the RES rules regarding "cost-effective retail renewable distributed generation." Proposed Rule 3656 begins with "It is the Commission's policy that utilities should meet the RES in the most cost-effective manner. . . ." CEO asserts that the Commission has historically interpreted this to apply to a RES Plan on a portfolio-level through retail rate impact rules. CEO is uncertain if the phrase "cost-effective retail renewable distributed generation" added in several places throughout the proposed RES rules creates a new paradigm where individual programs will be evaluated for cost-effectiveness. Should this be the Commission's intent, CEO requests additional time and information from the Commission before opining on the proposal. For example, the NOPR does not indicate: how the Commission proposes to determine cost-effectiveness; whether there will be cost-benefit test that would be applied; or at what level (e.g., program or portfolio) such a test would apply. CEO requests that the Commission, before adopting such an approach, provide clear answers to the above questions.

CEO is also concerned about how a cost-effectiveness or cost-benefit test would be applied to renewable energy programs directed toward low-income customers. Currently, utility demand side management programs must have a Modified Total Resource Cost Test

(mTRC) score above 1.0 to be found cost-effective. However, programs directed toward low-income customers are not required to achieve an mTRC of 1.0 or above.

CEO also requests clarification from the Commission on what types of renewable generation programs are subject to the RES planning process. The NOPR appears to suggest that the RES planning process will focus on the acquisition of distributed retail generation and certain other small (i.e., below 20 MW) resources. CEO asks the Commission to clarify whether it intends that WindSource, RenewableConnect, or CSGs will be acquired through a RES planning process or if the Commission intends for a utility to include these in its ERP filings. CEO also seeks clarification about whether QFs under 20 MW in size for which the utility has established tariffs under proposed Rules 3903 and 3904 would participate in the ERP process or whether the Commission intends to implement a process in the RES plan for QFs under 20 MW in size to seek a legally enforceable obligation from the utility.

Energy storage is declining in price and becoming an option for utility acquisition as well as for customers that participate in retail distributed generation programs. Therefore, CEO recommends that the RES Compliance Plan rules require a utility to include energy storage as part of its acquisitions in its RES Compliance Plan.

CEO also recommends that the Commission require that any incentives or programs that serve low-income or underserved customer groups addressed in the RES rules have corresponding language requiring that a utility include those programs or incentives in its RES Compliance Plan. For example, as discussed later, CEO supports the Commission's efforts to expand CSG capacity for customer groups identified in statute, including populations of "renters, low-income utility customers, and agricultural producers" and recommends requiring that a utility be required to include in its RES Compliance Plan a program or other method of acquisition to ensure that this goal is achieved. CEO also

supports the Commission's proposal to allow customers to contribute excess bill credits to a third party and recommends additional rule language requiring a utility to include details on any program related to the contribution of excess billing credits from CSGs to third parties in their RES Compliance Plans.

The Commission has proposed striking several requirements that a utility currently must include in its RES Compliance Plan filing. CEO's comments here directly address two of those proposed changes.

First, the NOPR proposes eliminating the requirement that a utility include an estimate of the RESA funds available during the period covered by the RES Compliance Plan. CEO suggests that RESA funds are still needed for smaller eligible and renewable energy systems and to support low-income programs. Therefore, it is essential that the Commission and other interveners be presented a clear picture of the RESA funds that are available to support such programs.

Second, consistent with other language in the rules that appears to move away from RECs as a mechanism to demonstrate compliance with the RES, the NOPR proposes to eliminate current Rule 3657(b)(XV) and remove the requirement that a utility explain how RECs are tracked and how RES compliance is calculated. CEO reiterates its earlier concern that moving from RECs as the RES compliance mechanism represents a significant departure from current practice that is not well justified and that the approach raises the risk of a double counting of the environmental benefits of renewable or eligible energy resources. Therefore, we recommend that the Commission not strike this requirement.

The Commission proposed several questions in its NOPR related to proposed Rule 3656 to which CEO responds below.

> *What is the appropriate and discrete role for the Commission in setting acquisition targets or capacity size limits to support the growth of retail renewable distributed generation and the growth of CSGs?*

CEO considers the question of the appropriate role of the Commission in determining a minimum and maximum market size to be an essential one. CEO's response about the Commission's role in ensuring market access underpins many of our comments. While the development of retail renewable distributed generation and CSGs will change annually and across regulated utilities, CEO considers the Commission's appropriate and discrete role to ensure that all customers have reasonable access to retail renewable distributed generation or CSGs and that those programs comply with the statutory retail rate impact cap.

The implementation of minimum acquisition targets supports this goal of providing access by ensuring that the market is not unduly constrained. CEO recommends that as the Commission considers its role in placing an upper limit on CSG or retail distributed generation programs that it consider the impacts that a cap or maximum size will have on thriving markets, which CEO believes should be permitted to progress without undue regulation by the Commission. To that end, CEO suggests that in adopting any maximum program size that the Commission do so based on statutory criteria of ensuring that a RES Compliance Plan complies with the retail rate impact cap for RES compliance or to address reasonable concerns about system reliability. Finally, CEO suggests that the Commission still has a role in ensuring equitable market access for low-income residential customers and other underserved customer groups and that the Commission can set expectations, specific targets, or incentives for retail distributed generation, CSG, or other utility programs that are part of a utility's four-year RES planning cycle.

Consistent with the Commission's question about its role in CSG markets, CEO also recommends that just as the Commission contemplates a stakeholder framework for assessing ERP modeling software and assumptions to be revisited in four-year ERP planning cycles, the Commission develop a framework for reviewing market access and

participation in retail renewable distributed generation and CSG programs. Based on the outcome of this process, the Commission may then set expectations or specific targets for utility programs, which the utility will then respond to by developing programs supported by the stakeholder process. This same framework would be utilized in the next four-year RES cycle to determine if market access remains a concern for certain demographics or if new, underserved, identifiable markets have emerged.

> *What improvements should the Commission make to its Electric Rules and its regulatory processes with respect to market size, the pace of market growth, and interrelationships between the retail renewable distributed generation and CSG markets?*

As noted above, CEO supports the Commission's effort to integrate ERP and RES planning. We recommend the Commission also add Distribution System Planning to this integration. We also believe that a non-litigated, pre-ERP process could facilitate better understanding of what will or should be included in an ERP and may reduce some of the time for the Phase I modeling process.

CEO understands that one of the purposes of the Electric Rules is to establish uniform requirements for applicable utilities. However, rather than establishing rigid requirements for utilities to address markets in these rules, CEO proposes the Commission require utilities to evaluate these markets, their health, and their needs as it relates specifically to each utility in each four year resource planning cycle.

> *Should it be necessary for the utility to specify in each RES Compliance Plan its plan to acquire specifically: retail renewable distributed generation from residential retail customers; retail renewable distributed generation from nonresidential retail customers; wholesale renewable distributed generation; and eligible energy resources to be acquired pursuant to the ERP Rules?*

CEO supports this, as it increases transparency and market certainty.

C. Rule 3657: Standard Rebate Offer, REC Purchases, and Contracts

In proposed Rule 3657, the Commission reduces the Standard Rebate Offer ("SRO") from \$2.00 per Watt to \$0.00 per Watt. The Commission also asks the following question:

> *Given that § 40-2-124(1)(e)(I.5), C.R.S., states that the Commission may set the SRO at a lower amount than \$2.00 per watt "if the Commission determines, based upon a qualifying utility's renewable resource plan or application, that market changes support the change," should the Commission adopt this proposed rule given the applications and RES Compliance Plans filed by Public Service in Proceeding Nos. 11A-135E, 11A-418E, 13A-0836E, 14A-0414E, and 16A-0139E and by Black Hills in Proceeding Nos. 12A-1207E, 13A-0445E, 14A-0535E, and 16A-0436E?*

CEO recognizes that the current SRO for both utilities is \$0.00 per Watt, as established and maintained in the proceedings referenced above, and that the Commission's proposed change is an effort to align the language in the Commission's Rules with what is happening in practice. CEO notes that the Commission's proposed rule would both lower the SRO to \$0.00 per Watt permanently and remove any flexibility for the Commission to adjust the SRO later. Under current Rule 3658, with the SRO set at \$2.00 per Watt, the Commission has the flexibility to reduce the SRO to \$0.00 based on finding that then current market conditions warrant a lower amount. CEO agrees with the Commission that some customers appear to be unaffected by an SRO of \$0.00. However, CEO asserts that the current SRO of \$2.00 per Watt served as the basis for the incentives in CEO's Low-Income Solar Rooftop program. This is just one example of where having a non-zero SRO afforded the utility, stakeholders, and the Commission flexibility to offer an incentive to certain customer groups, including low-income customers, that need an incentive in order to participate in a utility retail distributed generation program.

CEO recognizes that there may be other avenues to offer incentives to support access to renewable energy for low-income and hard-to-reach or underserved customers. CEO supports the flexibility included in the current rule language recommends the

Commission retain the current rule language setting the SRO to $2.00 in proposed Rule 3657(a).

D. Rule 3658: Renewable Energy Credits

CEO supports the Commission's efforts to allow a utility to acquire RECs through purchase. As discussed above, CEO asserts that a REC represents the environmental attributes (non-energy benefits) of renewable generation and that without a corresponding retirement of RECs the generation from renewable energy has no claim to these environmental benefits.

If the Commission adopts proposed Rule 3658, then CEO recommends the Commission add to the end a statement that a utility cannot claim the non-energy attributes—including any and all credits, benefits, emissions reductions, offsets or allowances—of renewable energy if the RECs associated with that generation have been retained by the customer or are not otherwise possessed by the utility. This prohibition against claiming environmental benefits should apply to any utility marketing materials as well.

E. Rule 3659 and 3661: Cost Recovery and Retail Rate Impact

The Commission proposes several changes to the use of the RESA account and to utility reporting requirements for the RESA account that CEO believes merit further discussion. First, the Commission proposes removing RESA account reporting from utility RES Compliance Plans. Second, the Commission proposes to no longer consider the RESA surcharge as the principal measure of the retail rate impact, and consistent with that, proposes striking Rule 3660(c).

Proposed Rule 3661 provides the greatest detail on the Commission's proposal to sever the RESA surcharge from the measurement of the retail rate impact. However, despite the language of proposed Rule 3661(e), CEO is unclear exactly how the Commission

expects a utility to calculate the incremental cost of renewable energy or to demonstrate compliance with the retail rate impact as required by § 40-2-124(1)(g)(I), C.R.S. As discussed in CEO's comments in the Stakeholder Outreach Proceeding, CEO believes that the RESA is still necessary and important for compliance with the retail rate impact as well as the rest of the RES statute.

CEO requests that the Commission explain to stakeholders why the Commission is seeking these changes to the RESA and what outcome the Commission expects in moving to a new method for calculating the incremental cost. After CEO better understands the Commission's intent in these rule changes, we hope to offer additional comments.

The Commission asks the following question related to how the retail rate impact is currently calculated:

> *Is it necessary to retain the two-scenario process for calculating the retail rate impact using the same methods the utility uses for its ERP? Are other, less complicated methods now suitable?*

CEO may be open to considering an alternative to the RES/No RES calculation that has been the basis for determining the retail rate impact in a utility ERP. However, while the Commission seeks input on this issue, it has not identified any concerns or deficiencies with the current approach. Therefore, CEO has not developed an alternative proposal or recommendation. CEO recommends that the Commission host stakeholder discussions or at least allow time for stakeholder discussions outside the Commission on this topic before the Commission makes a final decision on this question. As the Commission considers responses to this question, CEO opines that the RES/No RES calculation has been a transparent approach for determining the incremental cost of renewable and eligible energy resources and whether a utility's acquisition of those resources satisfies the 2% retail rate impact cap.

F. Rule 3662: RES Compliance Reporting

In alignment with CEO's recommendations for proposed Rule 3656, CEO proposes that any incentives or programs for low-income customers or underserved customer groups that are adopted in the RES rules have corresponding reporting requirements added to the section. CEO also proposes that utilities include language in their RES Compliance Plans about how they will develop or maintain programs that encourage CSG subscriptions from customer groups identified in statute, including populations of "renters, low-income utility customers, and agricultural producers." Alternatively, utilities may provide a narrative describing why there is insufficient demand for retail distributed generation from these customer groups.

CEO does not support removing RESA reporting from RES Compliance Plans. CEO believes that providing an account of the current and projected RESA funds and the calculation of the 2% retail rate impact via the RESA has been an important tool for the Commission in considering the appropriate size of certain renewable generation programs and incentive levels, and it has ensured that a utility RES Compliance Plan satisfies the 2% retail rate impact cap.

CEO also recommends that the Commission add a provision to proposed Rule 3662 requiring utilities to report on the outcomes of any program related to the contribution of excess billing credits from CSGs to third parties in their RES Compliance Reports, as is further discussed in the CSG Rules section of these comments.

IV. Net Metering Rules (3675-3699)

The Commission's Net Metering Rules (current Rule 3664 and proposed Rules 3675-3699) implement the provision in § 40-2-124(1)(e)(I)(B), C.R.S., that requires investor owned utilities to allow customers' retail electricity consumption to be offset by retail renewable distributed generation. CEO supports the Commission's decision to move the Net Metering Rules to a separate section from the Renewable Energy Standard Rules.

A. Rule 3678: Eligible Retail Renewable Distributed Generation

CEO suggests that the Commission modify proposed Rule 3678(a) to clarify how utilities should calculate the appropriate system size for retail renewable distributed generation systems. Both the Commission's existing and proposed rule explains that a system shall be sized to supply no more than 120 percent of the customer's average annual electricity consumption, in compliance with § 40-2-124(1)(c)(II)(B), C.R.S. However, it is not clear based on this language how size should be calculated—whether it should be based simply on nameplate capacity—or the actual expected electrical output, which could be affected by shading, roof orientation and other site conditions. CEO's proposed modifications to proposed Rule 3678(a) make explicit that actual expected electrical output is the pertinent data point and that additional factors affecting output should be taken into account when making this projection. This will ensure that systems are sized optimally in accordance with both the 120 percent requirement and specific site conditions, and that customers are not needlessly installing undersized systems in certain conditions due to this rule being misinterpreted as a calculation based on nameplate capacity. Software capable of these calculations, such as the National Renewable Energy Laboratory's "PVWatts," is readily available to provide these site-specific calculations and is referenced elsewhere in PUC Rules.

CEO also suggests the Commission reconsider its approach to the calculation of the 120 percent limit under Rule 3678(a) and the annual utility bill data required. CEO believes that the intent of the 120 percent provision was to allow customers to meet their own energy needs but to prevent a customer from becoming an energy exporter. CEO supports the broader implementation of electric vehicles and other approaches to beneficial electrification that will help reduce greenhouse gas emissions. We suggest that the current approach of calculating the 120 percent limit of a retail distributed generation facility by

using historical consumption data may disadvantage customers who undertake beneficial electrification to near in time to when they install an on-site solar generating resource and may prevent those customers from meeting their own energy needs.

For example, if a customer chose to increase their electric load significantly less than a year before installing an on-site solar generating resource, the calculation of the preceding year's average annual consumption would not fully reflect a new addition of load. To illustrate this example further, a customer who acquires an electric vehicle and necessary charging equipment only six months before installing an on-site solar generating resource might not be able to offset all or most of their electricity usage with an appropriately sized system, because the new permanent load from the electric vehicle charging would only be present on six of the twelve months of annual utility data. Consequently, if a customer is aware of this process and desires an appropriately sized system, they might need to wait a year with the new load—while paying for the increased load for a year—in order to "count" the new load for purposes of the 120 percent statutory limit.

B. Rule 3679: Net Metering Credits

Current and proposed Rule 3679(a) states, "excess kWh shall be carried forward from month to month and credited at a ratio of 1:1 against the customer's retail kWh consumption in subsequent months." CEO suggests that, as the investor-owned utilities move toward time-of-use rates, and as customers install more energy storage systems, the approach of using a 1:1 kWh credit may make it difficult for customers to capture the full value of the production from their on-site solar generating resources. The problem arises because under a time-of-use framework energy produced and consumed at different times has different values with peak energy production being worth more than off-peak energy production.

CEO supports what it believes to be the Commission's response to this issue in proposed Rule 3679(d). The Commission proposes monetizing net metering credit by requiring a utility to multiply the amount of energy generated by the rate for the time period in which that energy is generated. This monetary credit is then carried forward each month on the customer's bill and can be applied to consumption in any time period or as a credit against the customers aggregated consumption. CEO believes that monetizing the net metering credit permits a retail renewable distribution generation customer greater ability to offset their generation while maintaining the intent of time-of-use rates to reflect the changing value of energy and reduced peak demand.

CEO recommends that the Commission consider revising proposed Rule 3679(a) to clarify that the 1:1 credit either *is* or *can be* monetized and carried forward. CEO prefers the former approach and recommends the following revision:

> If a customer with retail renewable distributed generation generates renewable energy pursuant to rule 3678 in excess of the customer's consumption, the excess kWh shall be <u>credited at a ratio of 1:1 by monetizing the kWh as a dollar value credit based on the utility prevailing rate when the kWh was generated</u>, carried forward from month to month, <u>and credited against the customer's retail kWh consumption on a dollar value basis in subsequent months</u>.

Under this approach, a customer could apply a credit generated during peak hours to another portion of her bill. However, a credit generated at an off-peak time could only be applied to the portion of the bill attributable to off-peak consumption. CEO believes that the approach of monetizing a credit is simpler for a customer to understand and track, and fairly and accurately captures the value of a net metering credit under a TOU rate.

C. Rule 3680: Metering Requirements

Proposed Rule 3680 revises requirements related to production meters and the Commission has solicited input from parties on additional changes contemplated regarding the use or requirement of production meters. CEO supports the reasonable use of estimates

of electricity production in lieu of a production meter. A production meter is necessary for measuring the RECs that the utility acquires from retail renewable distributed generation for compliance with the RES. However, measuring RECs is not necessary in cases where a utility is not acquiring RECs, and "net metering only" customers who are not participating in a utility incentive program and who retain their RECs should not be required to install a production meter.

If a customer is participating in a utility incentive program, CEO proposes that a proxy value or estimate be utilized for small retail renewable distributed generation systems in place of requiring those systems to have a production meter. This may be a tiered approach similar to the proxy volume included in proposed Rule 3681(d)(II) or it may be a system-specific estimate pursuant to proposed Rule 3678(a). CEO also proposes that the Commission consider requiring voluntary written consent from a larger retail renewable distributed generation customer if a utility deems a production meter to be necessary. The production meter cost is not a cost caused by the individual customer, but rather a cost that results from the need of the utility to track and record RECs for RES compliance.

The Commission asks:

> *If net metering is deemed to "cause" eligible energy to be generated, could estimates of the electricity produced by certain systems suffice for RES compliance purposes such that no production meter is necessary? For example, would estimates be sufficient for retail renewable distributed generation not over ten 10 kW? If estimates are suitable, should the Commission adopt the same or similar provisions for estimating the production of retail renewable distributed generation as in Existing Rule 3658(f)(X) which was applied for the upfront standard offers to purchase RECs?*

As stated above, CEO supports the estimation of production in lieu of a production meter, especially for small systems. Non-hardware, "soft" costs represent a significant

percentage of total retail renewable distributed generation system costs. CEO supports efforts to reduce these soft costs for retail renewable distributed generation customers.

D. Rule 3681: Rates for Net Metering

The Commission requested comments from stakeholders on a series of questions relating to proposed Rule 3681 and whether Commission rules should allow or establish a separate rate class for net metering customers. CEO understands that the Commission has the authority to establish different rates classes when it finds that there is sufficient commonality among a group of customers and that that group is sufficiently distinct from other groups of customers. While the Commission can implement different rate classes, it must find that new rates are just, reasonable, and non-discriminatory. CEO notes that the Commission has not looked in depth at the issue the cost and benefits of net metering, which CEO believes would be necessary for the Commission to assess whether a separate net metering rate could be just and reasonable. CEO suggests that before the Commission adopts a separate net metering rate that it conduct a study, such as a value of solar study, which would provide a foundation to evaluate the cost and benefits of net metering and may address whether those warrant a separate rate class.

V. Community Solar Gardens Rules (3875-3883)

The CSG Rules implement § 40-2-127, C.R.S., setting forth requirements for CSGs located in investor owned utility service territories. The intent of the Colorado General Assembly in passing the Community Solar Garden Act was to promote broader participation in renewable energy by encouraging the development and deployment of CSGs.[12] The statute also directs the Commission to formulate and implement policies that simultaneously encourage: (1) the ownership by customers of subscriptions in CSGs and

[12] § 40-2-127(1)(b), C.R.S.

other forms of distributed generation, (2) ownership in CSGs by residential retail customers and agricultural producers, including low-income customers, (3) the development of CSGs with attributes that the commission finds result in lower overall total costs for the utility's customers, (4) successful financing and operation of CSGs owned by subscriber organizations, and (5) the achievement of the goals and objectives of the RES.[13]

A. Rule 3881: Billing Credits and Unsubscribed Renewable Energy

In its final set of comments filed in the Stakeholder Engagement Proceeding on September 7, 2018, CEO supported the proposal by Energy Outreach Colorado (EOC) to allow utilities to contribute unsubscribed renewable energy and RECs to a third party administrator qualified and approved by the utility for the purpose of providing low-income energy assistance and bills reductions within the utility's service territory. CEO also suggested that the Commission add additional provisions in the rule to ensure a fair and transparent system, including (1) defining the term "qualified and approved third party administrators," and (2) specifying the criteria third parties must satisfy to become qualified and approved. CEO proposed new rule language that included provisions requiring a utility to present the details of its plan to allow contributions of billing credits and/or unsubscribed renewable energy and RECs to a third party administrator in its RES Compliance Plan. CEO envisioned this type of program being open to a number of entities, as long as the utility specified the criteria it was using to qualify the entities, along with other details, in its description of the proposed program in the RES Compliance Plan.

Proposed Rule 3881(a)-(c) include a version of EOC's proposal, which allows a CSG subscriber to contribute excess billing credits to the "nonprofit corporation established for low-income energy assistance pursuant to § 40-8.5-104, C.R.S." EOC is currently the only

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[13] § 40-2-127(5)(a)(IV), C.R.S.

entity that has been so designated under the statute. Unlike CEO's recommendation in the Stakeholder Outreach Proceeding, the proposed provisions allow only EOC to participate in such a program, excluding any other entities that may be equally suited to participate. CEO continues to recommend that such a program be open to multiple third party providers. CEO also recommends the Commission clarify the rate that will be applied to the calculation of the donated credit.

CEO further recommends changes to proposed Rule 3881(d) that require utilities to propose any new program for donating bill credits in their RES Compliance Plans and report on the outcome of this program in their RES Compliance Reports. The details in a RES Compliance Plan should include (1) the utility's proposed process for qualification and approval of third parties, to ensure third parties are treated in an equitable manner; (2) the criteria a third party must meet to become qualified and approved, to ensure the transparency of the evaluation system and allow third parties to be fully informed; (3) the method by which a utility will determine an equitable allocation of billing credits to multiple third party administrators; (4) the way in which the program will be marketed to customers as a renewable program, to ensure that low-income customers know that they are receiving benefits derived from renewable energy that are distinct from traditional bill assistance; and (5) a reporting methodology to be included in each Annual RES Compliance Report. The details in a RES Compliance Report should include the total number of CSG excess billing credits that could have been, and that actually were, contributed to a qualified third party administrator for low-income energy assistance.

Because a bill credit donation program is new and there are still many details to be determined, presenting this information in RES Compliance Plans and RES Compliance Reports filed at the Commission is important for allowing the Commission and stakeholders an opportunity to provide feedback on the program. CEO appreciates Commissioner

Koncilja's attention to this issue and believes our recommended approach will alleviate any concern over which entities may participate in such a program, as well as ensuring there is an avenue through which the program can be examined further by the Commission and stakeholders.

B. Rule 3882: Purchases from CSGs

In proposed Rule 3882(a), the Commission has proposed striking the language explaining that an investor owned utility's plan for the acquisition of renewable energy and RECs from CSGs shall be part of the RES Compliance Plan. CEO requests that the Commission provide additional information about the intent and purpose of this change. CEO cannot tell from the proposed rule language whether the Commission suggests that utilities file a separate plan for the acquisitions of CSGs or whether the proposed rule simply leaves open the question of the most appropriate avenue for acquiring CSG power. The Commission posed a related question about whether it should continue to establish the acquisition targets for CSGs as part of the utility's RES Compliance Plan proceeding or in other proceedings. CEO believes the RES Compliance Plan is still the most appropriate proceeding for the Commission to establish CSG acquisition targets related to RES compliance.

The Commission's proposed Rule 3882(a) also requires that a utility dedicate 50 percent of CSG purchases to residential, agricultural, and small commercial customers, and allows the utility to propose a standard offer price for the purchase of RECs from such customers. While CEO appreciates the Commission's acknowledgment that these customer classes require special provisions to ensure that CSGs are meeting the statutory mandate to expand access to solar, we suggest the Commission consider a slightly different approach that may better ensure the financeability of CSGs that serve these kinds of customers so that the CSG market in Colorado continues to thrive. CEO supports the recommendation of

the Colorado Solar and Storage Association (COSSA) and the Solar Energy Industries Association (SEIA) in their initial comments in this proceeding, which proposes requiring utilities to put forward a standard offer credit adder which will help offset the additional cost of serving these customers classes, in addition to a standard offer REC price for low-income customers in particular. This approach will help address the economic barriers to serving these customers, which is essential for the financing and development of CSGs with a high percentage of residential, agricultural and small commercial subscribers. Grid Alternatives also supported this type of approach in its initial comments in this proceeding, noting that "standard offer incentives or adders are common and nationally proven mechanisms for spurring low-income customer adoption and participation by other underserved market segments…"[14] CEO believes this approach, instead of or in addition to a 50 percent carve-out, will result in a more robust and sustainable market for CSGs in Colorado. The health of this market will have clear economic development benefits for the state, while also benefiting consumers by allowing them to save money on their energy bills, reduce their carbon footprint, and invest in locally produced clean energy in their community.

In the Stakeholder Outreach Proceeding, CEO, along with other parties, recommended adding a provision to rules permitting acquisitions of CSGs outside of a utility's RES Compliance Plan and that subscribers to these CSGs would not be required to sell or transfer their RECs to the utility. CEO continues to recommend this provision be adopted, as it would serve the goals of providing more equitable access to CSGs for underserved customer types and classes, and ensuring that CSGs are available to customers that wish to subscribe. The current CSG market in Colorado is artificially

[14] Initial Comments of GRID Alternatives, Inc., filed in Proceeding 19R-0096E, at 26.

constrained by the maximum CSG capacity approved by the Commission through utilities' RES Compliance Plans. CSG developers are bound by this maximum capacity and cannot sell CSG power to as many customers as are demanding it. This provision will allow the market to function in an unconstrained manner and meet the customer demand for CSG power, thereby encouraging broader participation in CSGs. This will ensure that customers that are interested in subscribing to a CSG—including those that have been historically underserved—are able to do so, even when utilities' RES requirements have already been met. This is similar in concept to the way in which net metering customers have the ability to interconnect distributed generation outside of a utility's RES Compliance Plan and incentive program.

VI. Qualifying Facilities Rules (3900-3953)

CEO supports the Commission's proposal to use the competitive bidding process of a quadrennial ERP to comply with PURPA. CEO agrees with the Commission that QFs 20 MW or greater should compete with all other resources in the utility's all source solicitation. However, because the FERC has established a rebuttable presumption that QFs that are 20 MW or smaller are not competitive with larger facilities, CEO further recommends that the Commission establish a separate bid analysis and selection process for QFs between 5 and 20 MW.

The Commission states that it seeks comments on two options for tariff-based determination of avoided costs for projects greater than 100 kW and less than the minimum project size eligible to bid into the ERP. Option A entails the use of computer-based modeling to establish avoided costs, which could be applied as the differential revenue requirement approach. Option B entails a "market-based mechanism" preferably tied to a Phase II ERP solicitation.

While not offering a legal analysis, CEO notes that requiring QFs 20 MW and smaller to compete with larger resources as part of a utility's all source solicitation may not comply with PURPA. FERC rule 18 C.F.R. 292.309(a) makes an exception from PURPA's "must buy" provision in circumstances where the QF has access to wholesale markets or a regional transmission organization. However, 18 C.F.R. 292.309(d)(1) provides a rebuttable presumption that 20 MW and smaller QFs are discriminated in the market. The inability for QFs 20 MW and smaller to compete with other larger resources is evidenced by the fact that no QF of that size has ever won a bid in Public Service's or Black Hills's ERP Phase II bidding process. Therefore, CEO recommends that the Commission does not implement a rule that requires the Commission to determine whether competitive bidding as part of the utility's all-source solicitation is reasonably accessible for QFs 20 MW and smaller. Instead, the Commission should allow these smaller QFs to bid into the all-source solicitation, but the Commission and the utility should conduct a separate bid analysis leading to separate resource acquisition process for these smaller QFs. A separate bid selection process through competitive bidding for resources 20 MW and under complies with PURPA because it does not force these smaller QFs to compete with larger resources. This process is also consistent with the Commission's historic approach of using competitive bidding to acquire new resources in an ERP and to set a price for avoided cost.

CEO does not have specific rule language to propose at this point, but proposes that competitive bidding would be open all resources 5 MW an up. A utility's Phase II 120-day report would identify the average price of all bids from QFs that are 5-20 MW in size. That average price would then become a clearing price. The utility would then award a contract to all bids for QFs between 5-20 MW in size that provided a bid price lower than the average bid price. The capacity available from those QF contracts would reduce the overall

new capacity that the utility could acquire from resources larger than 20 MW acquired through the competitive bidding process.

CEO suggests that the Commission extend its new tariff-based approach to setting the avoided cost for QFs between 100 kW and 5 MW.

VII. Generation Interconnection Procedures (3668-3675)

CEO supports the Commission's efforts to modernize and update the interconnection rules. However, CEO is concerned that, as stated in the NOPR, the Commission relied on utility comments from the Stakeholder Outreach Proceeding as the foundation for the proposed rules.

In the Stakeholder Outreach Proceeding, CEO submitted proposed revisions to the Commission's interconnection rules that were intended to improve the clarity and organization of the rules, and to modernize, standardize, and streamline the interconnection process. CEO's proposed changes would allow utilities to process interconnection requests efficiency while ensuring the rules are inclusive of new technologies.

CEO also supported the joint petition of Energy Freedom Coalition of America, the Colorado Solar Energy Industries Association, Sunrun, Inc., and Vote Solar to open a rulemaking to modify the interconnection rules and address the Small Generation Interconnection Procedures (SGIP), for the primary purpose of adding energy storage guidelines to the scope of current Rule 3667.[15] In CEO's notice of intervention in that proceeding, CEO suggested that the Commission broaden the scope of the proposed rulemaking to update the SGIP in a more holistic way to align our state interconnection policies more closely with federal Standard Interconnection Agreements and Procedures for

[15] Proceeding No. 17M-0131E, Petition to Open a Rulemaking Proceeding, at ¶¶ 3-4.

Small Generators.[16] CEO continues to maintain that the updated Commission rules should align with FERC Order 792.

CEO also continues to support its prior position in the Stakeholder Outreach Proceeding that the Commission should modify the rules addressing storage systems. As we stated in comments, integrating energy storage technologies across the electric grid can result in many benefits for utilities, their customers, and society as a whole. These benefits include more efficient utilization of grid resources, the deferral or avoidance of costly upgrades, increased grid reliability, the provision of capacity reserves and voltage support, reduction of peak demand, avoidance or mitigation of system disruptions, support of higher penetrations of renewable energy on the grid, and increased consumer control over energy use and costs.

A. Rule 3853: General Interconnection Procedures

In the NOPR, the Commission notes CEO's 2018 request for a partial variance in Proceeding No. 18V-0594E from current Rules 3667(e)(XI) and 3667(j)(VII) for a Level 1 system. The Commission requests comments on whether the insurance amounts set forth in this rule continue to be appropriate. CEO asserts that the current insurance requirement for Level 1 systems is not appropriate. We propose that the Commission eliminate the current requirement in proposed Rule 3854(c)(VII) for $300,000 in liability insurance coverage for Level 1 systems (currently designated as 10 kW or less). Should the Commission find that a requirement for liability insurance for Level 1 systems is still necessary, CEO proposes that the Commission require a reduced amount—such as $100,000.

[16] Proceeding No. 17M-0694, Notice of Intervention of the Colorado Energy Office.

While any requirement for liability insurance for Level 1 systems should properly account for customer, developer, and utility needs and circumstances, a review of state liability insurance policies for Level 1 systems indicates Colorado's current policy is more stringent than most other states. Through its research, CEO found that nine states do not have statewide interconnection policies or do not address liability insurance in state interconnection policies. Of the remaining 41 states, 29 states and the District of Columbia do not require additional liability insurance for Level 1 systems. Five states determine that utilities can require liability insurance for Level 1 systems if the amount is "reasonable" or by using other indeterminate criteria. Of the remaining seven states with insurance requirements, two require $100,000 in liability insurance coverage and five states require $300,000 in liability insurance coverage for Level 1 systems. Furthermore, more than half of states consider Level 1 systems to have a maximum capacity of Colorado's current 10 kW cap, meaning these reduced liability insurance requirements are deemed appropriate for systems that are considered Level 1 or Level 2 system in Colorado.

CEO asserts that a reduced amount of liability insurance coverage is appropriate for Level 1 systems based on its experience administering its Low-Income Rooftop Solar program for Weatherization Assistance Program ("WAP") clients. The purpose of this program is to reduce income-qualified clients' utility bills and provide distributed generation access to a traditionally underserved demographic. The average solar photovoltaic installation in the Low-Income Rooftop Solar program is 3.0 kW. In certain instances, the $300,000 liability insurance requirement clients creates a barrier to expanding distributed generation access to this group.

B. Rule 3854: Level 1 Process

CEO believes that the Commission's proposed approach to the Level 1 interconnection process may present a barrier that disadvantages smaller retail distributed

generation systems in Colorado. CEO supports the Commission's efforts to modernize and simplify the interconnection processes; however, we recommend that the Commission does not rely so heavily on utilities to develop its proposed interconnection policy. Instead, the Commission should direct the utilities to work with CEO and other stakeholders in a series of workshops after the initial hearings to develop a joint proposal to update and modernize the Level 1 interconnection process without forfeiting any reliability of the electric grid.

CONCLUSION

For the reasons enumerated herein, CEO respectfully requests that the Commission consider these comments in this rulemaking proceeding.

Respectfully submitted this 1st day of May, 2019.

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